89 FERC ¶ 63,007

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Company
and
Central and South West Corporation

Docket Nos. EC98-40-000
ER98-2770-000
ER98-2786-000

INITIAL DECISION

(Issued November 23, 1999)

Appearances

Stephen Angle; *Thomas L. Blackburn*; *J. A. Bouknight, Jr.*; *Edward J. Brady*; *Kevin F. Duffy*; *Carmen L. Gentile*; *Douglas G. Green*, *Charles Hokanson, Jr.*, *B. Kelly Kiser*; *James F. Mauzé*, *Jane I. Ryan*; *Samuel T. Perkins*, and *Linda L. Walsh* for **American Electric Power Company**

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Randolph Lee Elliott, *Susan N. Kelly*, *Richard Meyer*, *Allen Mosher*, *David W. Penn*, *Debra H.Rednik*, and *Wallace F. Tillman* for **American Public Power Association and National Rural Electric Cooperative Association**

Mary W. Cochran and *Paul R. Hightower* for **Arkansas Public Service Commission**

Brian Donahue and *Zachary David Wilson* for **Arkansas Water and Light Commission and the City of Hope**

Christopher C. O'Hara and *Frederick H. Ritts* for **Blue Ridge Power Agency**

Adrienne E. Clair, *Montina M. Cole*, *T. Alana Deere*, and *Sherry A. Quirk* for **Brazos Electric Power Cooperative, Inc.**

Ronald J. Brothers and *Jeffrey A. Gollomp* for **Cincinnati Gas & Electric Company** and **PSI Energy, Inc.**

Mary Margaret Farren, *Jeffrey A. Gollomp*, and *Mike Naeve* for **Cinergy Services, Inc.**

Robert A. Jablon and *Thomas C. Trauger* for **Cities of Dowagiac and Sturgis, Mich.**

Paul A. Cunningham, *Richard B. Herzog*, and *Peter Thornton* for **Commonwealth Edison Company**

Daniel T. Donovan, *Mitchell F. Hertz*, *Michelle T. Palmer*, and *Edward N. Rizer* for **Dayton Power and Light Company**

Howard Benowitz and *Alan I. Robbins* for **East Kentucky Power Cooperative** and **City of Hamilton, Ohio**

William H. Burchette, *Matthew J. Jones*, *A. Hewitt Rose*, and *Christine C. Ryan* for **East Texas Electric Cooperative**; **Northeast Texas Electric Cooperative**; **Tex-La Electric Cooperative of Texas, Inc.**; and **Blue Ridge Power Agency**

Mark R. Haskell, *Daniel A. King*, *James W. Moeller*, and *Kathryn L. Patton* for **Electric Clearinghouse, Inc.**

Samuel Behrends IV, *Andrea J. Chambers*, *Joseph Hartsoe*, and *Sarah G. Novosel* for **Enron Power Marketing, Inc.**

Kim Despeaux, *Mary Margaret Farren*, and *William S. Scherman* for **Entergy Services, Inc.**

Susan Hedman and *Michael Mullett* for the **Environmental Coalition**

Eric A. Eisen and *Nikki Shoultz* for **Indiana Utility Regulatory Commission**

Samuel Grossman, *David M. Kleppinger*, *Samuel Randazzo*, *Kimberly Wile*, and *Derrick P. Williamson* for **Industrial Energy Users - Ohio and West Virginia Energy Users Group**

James Boyle and *Brian Lederer* for **International Brotherhood of Electrical Workers and Locals 1002 and 738**

David D'Alessandro, Kelly A. Daly, Mylie A. Needle, and *Richard Raff* for **Kentucky Public Service Commission**

John Michael Adragna, Patrick Henry, and *John M. Sharp* for **Louisiana Cooperatives**

Noel J. Darce, Michael R. Fontham, and *Paul L. Zimmering* for **Louisiana Public Service Commission**

David L. Schwartz and *Joseph A. Simei* for **McKinsey & Co. and Morgan Stanley Dean Witter**

Patricia S. Barrone, Henry J. Boynton, David D'Alessandro, Jennifer M. Granholm, Gregory O. Olaniran, and *David A. Voges* for **Michigan Public Service Commission and the State of Michigan**

David S. Berman, Paul M. Flynn, Arnold B. Podgorsky, and *Michael E. Small* for **Midwest ISO Participants**

Steven Dottheim, Scott Hempling, and *R. Blair Hosford* for **Missouri Public Service Commission**

Barry Cohen for the **Ohio Consumers' Counsel**

Gregg D. Ottinger and *Jon R. Stickman* for **Ohio Municipal Energy Group**

Scott A. Campbell and *Robert P. Mone* for **Ohio Rural Electric Cooperatives, Inc.**, and **Buckeye Power, Inc.**

Robert L. Daileader, Jr.; *Karen Georgenson Gach*; *John Harver*; and *Robert Stewart* for **Oklahoma Gas and Electric Company**

Ben Finkelstein for **Oklahoma Municipal Power Authority**

J. Cathy Fogel, Sang Y. Paek, and *Robin E. Remis* for **Ormet Primary Aluminum Corporation**

Steven M. Sherman for **ProLiance Energy, LLC**

Duane W. Luckey and *Thomas W. McNamee* for **Public Utilities Commission of Ohio**

John R. Garry and *Howard Zelbo* for **Salomon Smith Barney Inc.**

Steven M. Kramer and *Bret A. Sumner* for **Sharyland Utilities, L.P.**

Douglas F. John for **South Texas Electric Cooperative, Medina Electric Cooperative, and City of Robstown**

William F. Dudley, Wendy N. Reed, and *Alan J. Statman* for **Southwestern Public Service Company**

Kim M. Clark for **Texas Electric Cooperative; Medina Electric Cooperative**; and **City of Robstown, Tex.**

Floyd L. Norton IV and *Bruce L. Richardson* for **Texas Utilities Electric Company**

Randolph Lee Elliott, Milton J. Grossman, Carrie L. Hill, Robert A. O'Neil, Debora H. Rednik, and *Benjamin L. Willey* for **Transmission Dependent Utility Systems**

Grant Crandall, Douglas Parker, and *Judith Rivilin* for **United Mine Workers of America, AFL-CIO**

Joanne F. Goldstein for **Utility Workers Union of America, AFL-CIO**

C. Meade Browder, Jr. and *James C. Dimitri* for **Virginia State Corporation Commission and its Staff**

Charles W. Ritz III for **Wabash power Association**

Daniel E. Frank, Keith R. McCrea, and *J. M. Shafer* for **Western Farmers Electric Cooperative**

Becky M. Bruner for **Western Resources, Inc.**

John J. Bartus, Edith A. Gilmore, Gary D. Levenson, James A. Pepper, Charles F. Reusch, Stanley A. Berman, and *Richard L. Miles* for the **Staff of the Federal Energy Regulatory Commission**

NACY, Administrative Law Judge:

I. PROCEDURAL HISTORY

On April 30, 1998, American Electric Power Company (AEP) and Central and Southwest Corporation (CSW) (collectively Applicants) filed a joint application under section 203 of the Federal Power Act (FPA or Act), 16 U.S.C. § 824b (1994), seeking authorization to consolidate their jurisdictional facilities through a merger whose closing date was to be March 31, 1999. Applicants also made additional filings relating to the operation of the system after the merger is consummated.

In Docket No. ER98-2770-000, Applicants filed (1) a System Integration Agreement, pursuant to which the system will operate on a coordinated basis after the merger is consummated; (2) a System Transmission Integration Agreement governing transmission system coordination; and (3) a Transmission Reassignment Tariff providing for the sale and reassignment of unused transmission capacity.

In Docket No. ER98-2786-000, Applicants filed a Joint Open Access Transmission Tariff and Standards of Conduct, under which the system will offer transmission services after the merger is consummated.

On July 17, 1998, the Commission requested from the Applicants additional information and explanation of the Competitive Analysis Screening Model (CASM) that the Applicants submitted to evaluate the effect of the merger on competition. Applicants provided such information on August 11, 1998.

On November 10, 1998, the Commission issued its order [1] establishing hearing procedures. By order issued November 12, 1998, this Commission's Chief Administrative Law Judge designated me to preside at the hearing and to issue an initial decision.

After extensive discovery supervised by a special Discovery Judge, public hearing was held in Washington, D.C., June 29-July 19, 1999. Applicants, numerous Intervenors, and the Commission's Staff (Staff) presented testimony and evidence. After evidentiary

[1] 85 FERC ¶ 61,201 (1998).

submissions had been completed, due-dates of briefs were established, [2] but page limitations were not imposed. [3] The evidentiary record was closed July 19, 1999. [4]

Since the close of the hearing, a number of intervenors have withdrawn their opposition to the merger or to some of its aspects. On August 17, 1999, I certified to the Commission an uncontested offer of partial settlement submitted by the Applicants on July 14, 1999, calculated to dispose of all issues outstanding in these proceedings between them and the Missouri Public Service Commission (PSCMo).

On October 15, 1999, Dayton Power & Light Company (DP&L) filed a motion requesting that I take official notice of the Alliance Companies' supplement to their RTO application. Applicants answered, opposing that motion, on October 26, 1999. I have examined the motion and all its attachments and cannot find that they tend to prove or disprove any substantial issue in these proceedings.

Meanwhile, on June 28, 1999, Applicants had filed a motion seeking a waiver of the initial decision in Docket Nos. EC98-40-000 and ER98-2770-000. Staff and a number of Intervenors answered, opposing that motion. By order [5] issued July 28, 1999, the Commission (1) denied Applicants' motion and (2) set a due-date of November 24, 1999, for the initial decision in Docket Nos. EC98-40-000 and ER98-2990-000. The third proceeding, Docket No. ER98-2786, was not affected by that motion or that order, but, for the sake of efficiency, it is being decided on the same time schedule.

The Commission's order of July 28, 1999, necessitated a recasting of the briefing arrangements to accommodate the November 24 deadline. On July 29, 1999, therefore, I issued an order accelerating the brief due-dates and imposing page limitations on all briefs.

Timely initial and reply briefs have been filed and duly considered. Any finding or conclusion urged in any of them, but not made or drawn in this initial decision, has been evaluated and found either to lack merit or significance or to tend only to lengthen this decision without altering its substance or effect.

II. FINDINGS OF FACT

[2] Tr. 2459, confirmed by my order issued July 21, 1999.

[3] Tr. 2464.

[4] Tr. 2460.

[5] 88 FERC ¶ 61,121 (1999).

AEP owns seven utility operating subsidiaries that serve approximately 3 million customers in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. AEP also owns a subsidiary that sells power and energy at wholesale to affiliated and unaffiliated purchasers. It has 38 power plants with a capacity aggregating about 23,800 megawatts (MW). CSW owns four utility operating subsidiaries that serve approximately 1.7 million customers in Arkansas, Louisiana, Oklahoma, and Texas. AEP will continue as a registered holding company and will be the parent of AEP's and CSW's subsidiaries (jointly, the Combined System). The electric systems of AEP and CSW are not directly interconnected.

Applicants indicate that they have obtained rights to a 250 MW east-to-west firm transmission contract path to integrate the operations of the Combined System, and claim that this path is the equivalent of locating a 250 MW AEP generator directly within the CSW-Southwest Power Pool (SPP) market. This path increases the Herfindahl - Hirschman Index (HHI), used to measure market concentration in certain markets of SPP and the Electric Reliability Council of Texas (ERCOT). Applicants propose measures to mitigate concerns that arise out of the increased market concentration, including, among other things, a proposed 320 MW power sale in the SPP and ERCOT markets over a four-year period.

The intervenors expressed a number of concerns regarding the competitive effect of the proposed merger, including the data, assumptions, and analytic approach used in Applicants screen analysis; the competitive effects associated with transmission and generation; and mitigation measures.

In its November 10, 1998, order, the Commission applied the guidelines set forth in its *Merger Policy Statement* [6] and focused its review on the effect of the proposed merger on competition, rates, and regulation. In its review of competition issues, the Commission found that the three factors set forth in the *Merger Policy Statement* that would require a hearing are present. That is, (1) Applicants failed their own screen analysis; (2) there are problems concerning the assumptions and data used in Applicants' screen analysis; and (3) there are other factors that appear to suggest that Applicants' screen analysis may not fully capture the effects of the merger on competition.

With respect to retail competition, the Commission set for hearing the request of PSCMo for analysis of the impact of the merger on retail competition in Missouri. Further, the Commission indicated that Applicants' ratepayer-protection proposals may

[6] *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement Order No. 592*, 61 Fed. Reg. 68,595 (1996), FERC Stats. & Regs. ¶ 31,044 (1996), *order on reconsideration*, Order No. 5 92-A, 62 Fed. Reg. 33,341 (1997), 79 FERC ¶ 61,321 (1997).

not be sufficient-- but concluded that the proposed merger will not have an adverse impact on regulation.

The Commission also approved the use of the "pooling of interests" method of accounting for this merger and directed the Applicants to submit their accounting for the merger within six months after the merger is completed. In this regard, merger costs (transition, transaction, and regulatory processing costs) are estimated to be approximately $289 million. The Commission will require all AEP and CSW subsidiaries, subject to its jurisdiction, to charge transaction costs and regulatory processing costs to Account 426.5, and transition costs to operating expenses as incurred. To the extent that rate recovery of the merger costs is determined to be probable by the jurisdictional subsidiaries, such costs may be accounted for as regulatory assets in Account 182.3, and amortized over five years, commensurate with their recovery.

Two trial stipulations between Applicants and Staff were filed. The first, dated May 24, 1999, would resolve all issues between Staff and Applicants with the exception of issues pertaining to system integration agreements and ratepayer protection, and one reserved issue (the May 24 Stipulation). Staff's prefiled testimony addressed only the issues not resolved by that stipulation. The second stipulation, dated July 13, 1999, resolves all issues pertaining to the system integration agreements, except for one reserved issue related to the pricing of energy exchanges between AEP (AEP East) and CSW (AEP West) (the July 13 Stipulation). The trial stipulations also indicated an agreement among Staff and Applicants that the two reserved issues not resolved by the stipulations were to be presented directly to the Commission for resolution. By order issued August 27, 1999, I denied a Joint Motion of Applicants and Staff requesting adoption of limited briefing procedures concerning the two reserved issues.

III. DISCUSSION AND CONCLUSIONS

The issues in these proceedings may be reduced to three: First, whether Applicants' merger request is consistent with the public interest; second, whether the rates, terms, and conditions of the three rate schedules related to post-merger coordinated operations, filed in No. ER98-2770-000, are just and reasonable; and third, whether the joint open access transmission tariff providing for post-merger transmission and ancillary services filed in No. ER98-2786-000 is just and reasonable. These issues must be addressed in the context of the *Merger Policy Statement*.

This Commission's authority over mergers stems from Section 203 of the Federal Power Act (Act), 16 U.S.C. § 824b (1994). If the Commission finds a merger to be consistent with the public interest, it must approve it. In 1996, the Commission updated and clarified its merger procedures in the *Merger Policy Statement*. Since then, the Commission has concentrated on three issues: the effect of the merger on competition; its effect on rates; and its effect on regulation. Only the first two are set for hearing here.

A. Effect on Competition

Applicants have borne their burden of establishing that this merger would not produce adverse competitive effects. Its analyses and mitigation commitments remove any such danger. They have committed to the divestiture of 550 MW of specified low-cost generating capacity in Texas and Oklahoma as soon as feasible, consistent with reliability, besides agreeing to sell interim equivalent amounts of energy on terms that relinquish control over that energy. Their analysis, as supported by Witness Hieronymus confirms that Applicants' mitigation plans eliminate any Guidelines screen failures attributable to a combination of Applicants' generating facilities.

Intervenors' attacks on Hieronymus's evidence was unpersuasive. In all their criticisms of that evidence, I have been unable to find any convincing evidence of defects that would weaken the overall effect of that evidence. They rely on an assumption that Applicants will renege on their mitigation commitments--an assumption I am not willing to indulge on the strength of this record.

Applicants' Witness Henderson disposed of fears of vertical market power being vested in the merger partners. He demonstrated that the merger will not give Applicants the ability to use transmission to affect competition in an adverse manner. Exh. AC-900 at p. 8. Further, he reviewed data from the AEP and CSE OASIS sites, and was unable to find patterns of transmission refusals indicating that transmission personnel might have been providing preferential treatment to marketing affiliates. AC-900 at p. 9.

Witness Henderson also examined whether or not a combination of Applicants' transmission systems would create ability and incentive for the use of transmission to frustrate competition, and concluded persuasively that it would be difficult to the point of improbability. This was challenged by Witness Tabors for Enron Power marketing (Enron), but that challenge did not produce any direct evidence, but relied on raw OASIS data of requests for transmission service and the frequency of grants or refusals. This was clearly overborne by Henderson's evidence. AC-900, at pp. 43 and 49.

But this was not the end of it. AEP has committed to join a Regional Transmission Organization (RTO) that will be responsible to transmission access and/or the OASIS site, obviating even an appearance of preference by AEP.

Other attacks on Henderson's evidence were equally unavailing. Cinergy witness Fox-Penner criticized it for not addressing certain types of potential foreclosure behavior, but Henderson properly explained that such forms of non-targeted foreclosure behavior would not be realistic methods of frustrating competitors' transmission access. The Fox-Penner attack was fanciful and based on assumptions that have no support in the record. It also failed to show that the conduct he assumed would, in fact, be attractive to Applicants. If the fakeries he envisions cannot be done with profit, where would be the incentive to indulge in them? Fox-Penner did not explain.

Henderson's refutation of any suspicion that this merger will create an ability or incentive for Applicants to use transmission to frustrate competition was unshaken by cross-examination of the witness and by anything offered by intervenors.

Intervenors' attempts to demonstrate a necessity for AEP's joining the Midwest ISO are not convincing. As demonstrated by Witness Baker, excluding Allegheny Power System from the Midwest ISO (and its inclusion has not been established here) leaves AEP's tie capacity with the four Midwest ISO member is 16,138 MVA--less than the capacity of its interconnections with the four other Alliance participants, 18,359 MVA. Exh AC-408 at p. 15. It has even more interconnected transfer capability with the ten transmission owners that have not joined an RTO. *Id.*, at p.6.

AEP's proposed acquisition of the LIG Pipeline raises no danger of vertical market power. There are sufficient alternative natural gas transporters and providers in Louisiana available to meet generation needs. Any small amount of generating capacity not directly connected to other transportation systems is generally uneconomical, operating on low capacity factors. The combination of generating plants supplied only by LIG and Applicant's plants does not cause HHI increases sufficient to cause concern. Exh. AC-500, at p. 73.

B. Effect on Rates

1. *Applicants' Ratepayer Protection Measures Fully Shield Customers from Any Potential Adverse Effects of the Merger on Rates:*

Applicants have proposed a comprehensive series of measures that provide full protection for wholesale requirements and transmission customers from any adverse rate consequences resulting from the proposed merger. Exh. AC-403 at p. 16. These protections include:

a. Applicants will hold wholesale customers harmless from merger costs in excess of merger savings;

b. Applicants will provide an open season for requirements customers under cost of service rates if Applicants increase their rates;

c. Applicants will cap the production charge and freeze the transmission charge for formula rate customers through 2002;

d. Applicants will give formula rate customers the option to freeze their production charges through 2003 at levels that do not include merger costs;

e. Applicants will give transmission customers the option to switch to Applicants' open access tariff rates.

See Exh. AC-403 at p. 23 and AC-1600 at p. 11. These ratepayer protections augment protections already contained in Applicants' contracts with wholesale customers, and insulate the customers from adverse rate impacts due to the merger.

The Commission has urged merger applicants to negotiate ratepayer protection measures with their customers, and that is what Applicants have done. As a result, there are only two customers remaining in this proceeding that have sponsored testimony challenging Applicants' ratepayer protections, but neither of these customers' concerns has anything to do with the merger. Although the customers for which Applicants' ratepayer protections are designed are largely satisfied with Applicants' ratepayer protections, Staff witness McAndrew nevertheless argues that the protections are not adequate to protect ratepayers. McAndrew proposes additional measures that the customers have not sought (and in some cases oppose), that the Commission has rejected in other merger proceedings, and that Applicants have shown are unnecessary and unduly burdensome. His objections to Applicants' proposals must be rejected.

2. Ratepayer Protection Measures:

Applicants have proposed ratepayer protection measures for each ratepayer group. These protections are more than sufficient to ensure that affected ratepayers do not pay any merger costs that Applicants incur in excess of merger benefits. *See New York State Elec. & Gas Corp.*, 86 FERC ¶ 61,2 84 at p. 62,023 (1999).

a. Requirements Customers Under Negotiated Rates and Cos-of-Service Rates:

Applicants will protect requirements customers served under cost-of-service rates through Applicants' hold harmless commitment and open season proposal. Exh. AC-403 at pp. 35-36. Requirements customers that are now served under negotiated rates are protected from merger-related costs by the terms of their existing contracts. These contracts provide for fixed rates, so the merger cannot affect them.

Under the hold-harmless commitment, in any section 205 or 206 proceeding that develops rates using a test year that begins within five years after consummation of the merger, Applicants will bear the burden of proof that any merger costs included in the proposed rates are offset by merger savings included in the proposed rates. Under the open season proposal, requirements customers under cost-of-service rates will have an open season if Applicants file a rate increase that uses a test year that begins within five years of the consummation date of the merger and the Commission accepts the filing. -6. The Commission has stated that in the majority of circumstances the most meaningful ratepayer protection is an open season provision. *Merger Policy Statement* at p.30,124. These ratepayer protections are sufficient to ensure that ratepayers do not pay merger costs in excess of merger savings.

b. Stranded Cost Waiver:

Staff Witness McAndrew argues that Applicants should be required to waive their right to seek to recover stranded costs from requirements customers under negotiated rates and cost-of-service rates after their contracts expire (whether those expirations occur pursuant to the contract provisions or pursuant to the customer's exercise of its open season rights). His recommendation would only have an impact in those cases where the Commission would find stranded cost recovery warranted.

Although Witness McAndrew offered his proposal in the name of customer protection, the only remaining customers in these proceedings that have voiced concerns about Applicants' recovery of stranded costs are the Cities of Dowagiac and Sturgis, Michigan, and neither of these customers' stranded cost claims has anything to do with this merger. Sturgis gave notice to terminate wholesale service in 1996, more than a year before this merger was announced. That notice became effective in July 1999. Exh. AC-408 at p. 50. As a result, Sturgis is potentially liable for stranded costs, but this would be so regardless of whether the merger ever occurred. The Commission has rejected customer attempts to escape stranded cost responsibility in similar circumstances. *See Duke Power Co.*, 79 FERC ¶ 61,236 at p. 62,040-41 (1997).

The other customer's stranded cost argument is even more remote. Dowagiac gave notice to terminate wholesale service from AEP in 1997, effective in 1998. Dowagiac, which is not even a wholesale requirements customer of Applicants, argues that Applicants should be required to waive any stranded cost claims that they may have if Dowagiac acquires some of Applicants' existing *retail* customers. The potential recovery of these retail stranded costs is unrelated to the merger, and is a matter for the Michigan Public Service Commission. No intervenors remaining in the proceeding has expressed any concern as to wholesale stranded cost recovery by Applicants due to any actions in the future. None of the witnesses arguing in favor of a stranded cost waiver explained how the merger would increase these customers' exposure to stranded costs. Without any connection to the merger, these arguments fail.

The Commission has repeatedly ruled that arguments about stranded costs in merger proceedings are premature until customers seek to terminate their contracts, and that customers' arguments about stranded costs should be made in a separate proceeding when the stranded cost claim is made. For example, in *WPS Resources Corp.*, the Commission rejected the customers' request that the applicants be required to waive stranded cost claims, ruling that "no condition addressing the recovery of stranded costs should be placed on approval of the mergee' and that "any claims for stranded cost recovery should be addressed in a separate proceeding." 83 FERC ¶ 61,196 at 61,840 (1998). In *IES Utilities*, the Commission rejected the customers' request that the applicants' open season proposal be modified to include a stranded cost waiver, ruling that stranded cost issues should be pursued in a separate complaint proceeding. 81 FERC ¶ 61,187 at p. 61,838. In *Duke Power Co.*, customers sought waiver of stranded costs as a merger condition, arguing that a stranded cost obligation undermined the Applicants' pre-granted open season because it prevented them from taking full advantage of competition. The Commission ruled that the customers' stranded cost arguments were unrelated to the merger, and were already being considered in ongoing stranded cost proceedings. 79 FERC ¶ 61,236 at pp. 62,040-1. In addition, the Commission has repeatedly approved other mergers without requiring a stranded cost waiver. While some utilities have voluntarily agreed to waive stranded costs in certain situations, the *Commission has never ruled in a merger case that a stranded cost waiver was required to protect customers from merger-related costs.*

Witness McAndrew asserts that his proposal is consistent with the *Merger Policy Statement*, but the *Merger Policy Statement* says nothing about eliminating stranded cost recovery in connection with an open season or otherwise, and the cases discussed above (all of which post-date the *Merger Policy Statement*) show that the Commission does not share that interpretation. The Commission stated in Order 888 [7] that "the recovery of legitimate, prudent and verifiable stranded costs is critical to the successful transition of the electric utility industry to a competitive, open access environment," and reaffirmed that view in Order 888-A, [8] issued less than three months after the Merger Policy Statement. Order 888 at 31,634-35, 31,788-89; Order 888-A at pp. 30,176 and 30,347-48. The Commission added that it had "a responsibility" to allow for the recovery of stranded costs resulting from its open access regime, Order 888 at p. 31,790, and that it is fair for departing customers to pay costs legitimately incurred to provide service to them and which are now stranded, Order 888-A at pp.30,347-49 and 30,353. Nothing in the *Merger Policy Statement* reflects any intent to abrogate these fundamental principles.

Mr. McAndrew also claimed that a stranded cost waiver is needed for these departing customers to avoid creating a barrier to entry into the competitive marketplace following their contract termination, but he offered no explanation for this assertion, other than citation to the testimony sponsored by Sturgis and Dowagiac. Both of these customers' stranded cost arguments, however, are unrelated to the merger.

In addition, Witness Baker explained why McAndrew's assertion was erroneous. Exh. AC-415 at p. 12. Stranded cost charges compensate a supplier for charges that the supplier had a reasonable expectation of recovering but which are now above the market price. At the end of a contract, a wholesale customer may have to compensate its existing supplier for the above-market costs incurred to provide service to the customer, but that obligation remains whether the customer stays with its current supplier (and pays rates that include the pre-existing obligation) or finds a new one (and makes stranded cost payments for the pre-existing obligation). Its incremental supply costs, beyond the pre-existing obligations, will be determined in the competitive market, whether it takes service from its existing supplier or from a new supplier. McAndrew's unstated (and unproven) assumption is that by staying with its existing supplier, the customer will somehow secure (1) a discount below the market price or (2) the expected value of litigation over the size of the pre-existing obligation. This is illogical, because in addition to the market price the supplier is entitled to receive payment for the pre-existing obligation, regardless of whether the customer stays or leaves.

[7] Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Access Utilities and Transmitting Utilities,* FERC Stats. & Regs., Regulation Preambles ¶ 31,036 (1996) *("Order 888").*

[8] Order No. 888-A, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Access Utilities and Transmitting Utilities,* FERC Stats. & Regs., Regulations Preambles ¶ 31,048 (1997) *("Order 888-A").*

Further, even if McAndrew's "barrier to entry" argument were correct, which it is not, it would only relate to the merger if the alleged "barrier" somehow led the customer to remain with the existing supplier and to pay cost-based rates that included merger costs in excess of merger benefits. This unlikely scenario is appropriately addressed not by discarding the Commission's stranded cost policy, but rather by holding such customers harmless from rates that include merger costs in excess of merger benefits. McAndrew's proposal is unwarranted and at odds with Commission policy and should be rejected.

c. Calculation of Merger Costs and Benefits for Hold Harmless Commitment:

Applicants propose to use estimated merger costs and benefits to demonstrate compliance with the hold harmless commitment so as to reduce unnecessary litigation expense for all parties. Staff Witness McAndrew opposes Applicants' proposal. His arguments fail.

First, contrary to McAndrew's apparent assumption, Applicants are not proposing that estimated merger costs and benefits be used without regard to their reasonableness. Applicants would bear the burden of proof that their estimates are reasonable for purposes of determining whether merger costs included in rates exceed merger benefits. The proposal is similar to the use of projected data for setting rates, which is the Commission's preferred method. *See Southern California Edison Co.*, 8 FERC ¶ 61,099 at p. 61,375 (1979). As in any rate case, the Commission will judge whether Applicants have met their burden of showing that the use of their estimates is reasonable. If the Applicants can meet this burden, rate payers will be fully protected.

Second, McAndrew ignores the fact that any method for determining merger benefits--including his own--must rely on estimates, because Applicants will have to estimate what their costs would have been absent the merger.

Third, McAndrew ignores the fact that none of the customers that his proposal is designed to protect filed testimony opposing Applicants' proposal, and the one customer that submitted testimony on the subject supported Applicants' proposal to use estimated data.

Witness McAndrew proposes several other modifications to Applicants' hold-harmless commitment. First, he argues that Applicants should be required to present proof that system integration benefits exceed the cost of transmission required for system integration in order to include such transmission costs in rates. This proposal must be rejected. The relevant inquiry under the Commission's ratepayer protection policies is whether total merger costs included in rates are offset by total merger benefits; how individual cost and benefit items compare is irrelevant.

Second, McAndrew offers his recommendation on how specific cost items should be calculated in determining Applicants' compliance with their hold harmless commitment. This proposal must also be rejected. The Commission can review the propriety of Applicants' method if the issue arises.

Third, McAndrew offers his recommendation on what information should be included in Applicants' future section 205 filings to demonstrate compliance with the hold harmless commitment. This proposal cannot be accepted, since the amount and kind of information will depend upon the filing. It is appropriately reviewed in the proceeding in which the filing is submitted, not here.

d. Requirements Customers Under Formula Rates:

Applicants have provided requirements customers receiving service under comprehensive formula rates (all of which are Southwestern Electric Power Company ("SWEPCO") customers) several overlapping ratepayer protections that will ensure that they do not pay merger costs in excess of merger benefits. First, these formula rate customers will not be subject to merger transaction costs (even if offset by merger benefits included in rates) because these costs (which include regulatory costs) are not included in the formulas.

Second, these customers will receive the benefit of merger savings which are expected to exceed merger transition costs--because these benefits automatically flow through the rate formulas.

Third, the customers will not experience any merger-related rate increase through the year 2002, because (1) the production demand charges in SWEPCO's formula rates will be capped at 1998 levels (which include no merger costs) through the end of 2002,

and (2) Applicants propose to freeze the transmission demand charges in these rates at 1998 levels (which include no merger costs) through the end of 2002. [9] This cap and freeze provide adequate protection because, most, if not all, merger costs are expected to be incurred within two years of the merger (i.e., Spring 2002, assuming a Spring 2000 closing), well before this cap and freeze end. Exhs. AC-403 at p. 30, AC-1600 at pp.12:13.

Fourth, if merger transition costs do occur after 2002, Applicants' hold-harmless commitment will prevent their inclusion in formula rates unless offset by merger savings included in rates. This would remain in effect for test years that begin within five years of the consummation date of the merger. Exh. AC-415 at p. 30.

Fifth, in response to Witness Gross's argument that SWEPCO's rates should be fixed at the levels that SWEPCO projected before the merger was proposed, these customers can make a one-time election to fix the production demand charges for 2000-2003 at the levels that Applicants projected before the merger was proposed, subject to adjustment to reflect new capacity additions. Exh. AC-1600 at p. 11.

Together, these protections provide ample assurance that formula rate customers will not experience merger costs in excess of merger savings. While some of Applicants' formula rate customers initially raised some concerns regarding Applicants' ratepayer protections for customers under formula rates, Applicants have offered additional ratepayer protections for formula rate customers, and all of Applicants' formula rate customers have now settled and withdrawn from the proceeding. Thus, no customer that remains a party to this proceeding has presented any objection to Applicants' ratepayer protections for formula rate customers. This should be dispositive of the question of whether Applicants' ratepayer protections are adequate for formula rate customers.

e. Annual Compliance Filing:

Despite the fact that formula rate customers are protected by rate freezes and rate caps through 2002, can fix their production demand charges through 2003, and receive the benefit of a hold harmless commitment for five years, Staff Witness McAndrew argued that Applicants should also be required to make annual "compliance filings" documenting all merger costs and benefits. Shortly before the close of the hearing, McAndrew changed his compliance filing (now redesignated an "informational filing", but still just as burdensome) to include what he claimed was less detail. He contended that his new proposal was modeled after a filing requirement imposed in *Cincinnati Gas & Electric Co.*, 64 FERC ¶ 61,237 (1993) (*Cinergy*).

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[9] In the alternative, these customers can elect an annual option to switch to Applicants' open access tariff. Exh. AC-403 at p. 30:13-19.

The new McAndrew proposal would be more burdensome than that approved in *Cinergy*. McAndrew admitted that in *Cinergy*, the merging parties filed an annual Period I (historical) study drawn from FERC Form I data, and compared it to a single Period II (projected) study. Tr. 2430. McAndrew would require Applicants to submit, on an annual basis, both historical *and* projected data. Exh. S-208 at p. 7. McAndrew, who admitted he had never performed a merger savings study (Tr. 2433), reasoned that preparing annual projections added no more work since subsequent years' studies would build on prior years' studies. He initially claimed that factoring in changed circumstances each year would be the same under his and the *Cinergy* proposal, but later admitted that under the *Cinergy* requirement the changed circumstances would only have to be reflected in a Form 1-based historical study, not in a new projection. McAndrew explained in supplemental testimony that his original (and new) filing proposal was directed to formula rate customers alone. Exh. S-208 at p. 6.

McAndrew's compliance filing is unnecessary, unduly burdensome, and, like his stranded cost waiver proposal, at odds with Commission policy. The filing requirement in the *Cinergy* case--the sole case upon which McAndrew relies was designed to implement a ratepayer protection standard that the Commission no longer follows. *McAndrew admitted that, at the time the Cinergy case was decided, the Commission* required merger applicants to show that merger benefits exceeded merger costs. Tr.2433. Consistent with that requirement, the Commission required Cinergy to make an annual compliance filing to show whether merger benefits exceeded merger costs. McAndrew conceded that the Commission has eliminated the requirement that merger applicants make a showing of merger benefits. Tr. 2433; *see Merger Policy Statement* at p. 30,123.

Although Mr. McAndrew admitted that he was aware of the Commission's policy shift, [10] he failed to appreciate its significance to his recommendation. He also failed to check the Commission's reported decisions to see whether the Commission continued to require the informational filing required in *Cinergy* in *any* cases issued after the *Merger Policy Statement*. Tr. 2436. In fact, *no* merger case involving a hold-harmless commitment, decided after the *Merger Policy Statement* imposed an annual merger cost

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[10] He also admitted that, while he relied on the *Merger Policy Statement* for the *Cinergy* case, in fact the *Merger Policy Statement* makes no reference to the portion of *Cinergy*-- the required annual filing--that he relied upon. Tr. 2435. *See Merger Policy Statement* at p. 30,122.

and benefits filing requirement, [11] a fact of which Mr. McAndrew was unaware. Tr. 2436. The same factor that led McAndrew to propose his filing requirement for Applicants--the presence of formula rates--was present in many of these cases, yet no filing requirements were imposed.

The filing Witness McAndrew proposes is not warranted and is likely to produce more litigation involving Trial Staff, not less. McAndrew ignores the fact that formula rate customers are already protected by a rate freeze and rate cap through the end of 2002--well after the period when most if not all merger costs would be expected to occur, and can secure fixed production charges through the end of 2003. There is no need to track merger benefits and transition costs in view of these protections (merger transaction costs are already excluded from rates). McAndrew also ignores the fact that the formula rate hold-harmless commitment--the commitment that Mr. McAndrew's proposal is directed to does not even begin until 2003 in view of these protections. Mr. McAndrew's proposal also adds unnecessary complexity by requiring Applicants to catalog all costs and benefits rather than provide sufficient information to show that benefits exceed costs. There is no need for Applicants to establish the precise level of merger costs and benefits; indeed, there is no need for Applicants to establish that merger costs are outweighed by *merger benefits. Applicants need only show that merger costs included in rates are* outweighed by merger benefits included in rates. Applicants will demonstrate compliance with that requirement if the issue arises; as the Commission's prior orders show, no filing requirement is necessary to trigger that obligation. Finally, while McAndrew downplayed the burdensome nature of his proposal in his pre-filed testimony, he admitted on cross examination that he had no idea how much work a merger benefits study entailed. Tr. 2433. His proposal is rejected.

f. Other Proposals:

Witnesses Gross and McAndrew argue that the formula rate caps and freezes should remain in effect until the end of 2005. Exhs. ETC-500 at p. 12 (Gross), and S-208 at p. 5 (McAndrew). This is unnecessary. As discussed above, most if not all merger transition

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[11] *See PacifiCorp*, 87 FERC ¶ 61,288 (1999); *New England Power Co.*, 87 FERC ¶ 61,287 (1999); *Sierra Pacific Power Co.*, 87 FERC ¶ 61,077 (1999); *Wisconsin Energy Corp.*, 83 FERC ¶ 61,069 (1998); *WPS Resources Corp.*, 83 FERC ¶ 61,196 (1998); *Louisville Gas & Elec. Co.*, 82 FERC ¶ 61,308 (1998); *Long Island Lighting Co.*, 82 FERC ¶ 61,129 (1998) (divestiture case decided under *Merger Policy Statement* criteria); *IES Util., Inc.*, 81 FERC ¶ 61,187 (1997); *Union Elec. Co., 81* FERC ¶ 61,011 (1997); *Atlantic City Elec. Co.*, 80 FERC ¶ 61,126 (1997); *First Energy I*, 80 FERC ¶ 61,039 (1997); 81 FERC ¶ 61,110 (1997); *San Diego Gas & Elec. Co.*, 79 FERC ¶ 61,372 (1997); *Duke Power Co.*, 79 FERC ¶ 61,236 (1997); and *Public Serv. Co. of Colorado*, 78 FERC ¶ 61,267 (1997).

costs are expected to be incurred within two years of the consummation of the merger, well before the end of 2002; and formula rate customers can fix their production demand charges through the end of 2003 at levels endorsed by Gross. Exhs. AC-403 at p. 30 and AC-1600 at p. 11. (Merger transaction costs will be amortized over a longer period, but are not included in the formula rates.) In addition, formula rate customers will be protected by Applicants' hold harmless commitment after this period.

Witness Gross also argues that the open season should be extended to formula rate customers. This too is unnecessary. The availability of fixed demand charges during the rate protection period will protect formula rate customers from possible merger-related costs that exceed the merger-related savings, making an open season unnecessary. None of Mr. Gross's other proposals is necessary to ensure that merger costs included in rates are offset by merger savings.

g. Transmission Customers:

Transmission customers served under cost-of-service rates are protected from merger-related costs by Applicants' hold harmless commitment, discussed above. Mr. McAndrew addresses together Applicants' hold harmless commitment as it applies to transmission and requirements customers under cost-of service rates, and the discussion above refutes those arguments.

Transmission customers served under formula rates are protected from merger--related costs by Applicants' proposed rate freeze and hold harmless commitment. In addition, McAndrew's concerns about the ratepayer protections for these formula rate customers ignore the transmission customers' open season option to switch to Applicants' open access tariff. This gives any transmission customer that is concerned about merger costs being passed through its formula rate the option to take service under a stated rate, where any merger costs included in rates would be subject to review in a section 205 proceeding.

3. The Rate Schedules in Docket No. ER98-2770-000, as Applicants Have Agreed to Modify Them, Are Just and Reasonable:

In conjunction with their filing in Docket No. EC98-40-000 for authorization to merge, Applicants filed in Docket No. ER98-2770-000: (1) the System Integration Agreement; (2) the System Transmission Integration Agreement; and (3) the Transmission Reassignment Tariff. The System Integration Agreement ("SIA") (Exh. AC-416) is an agreement among the AEP operating companies that governs the integration and coordination of their power supply resources post-merger. Exh. AC-1300 at p. 3 (Baker). The SIA provides for the distribution of power supply costs and benefits between the two zones (corresponding to the pre-merger AEP and CSW systems). It will function in addition to, but not in substitution of, the existing AEP system interconnection agreement and the existing CSW system operating agreement. *Id.* at p. 4. Those existing

agreements will continue to govern the distribution of costs and benefits *within* the zones. *Ibid.*

The System Transmission Integration Agreement ("STIA") (Exh. AC-1401) establishes a framework under which the transmission facilities of the AEP operating companies and the CSW operating companies will be planned, operated, and maintained on a coordinated basis. Exh. AC-1400 at p. 5 (Bethel). The STIA is intended to supplement--not replace--the existing intra-system transmission agreements (*id.* at p. 5), which will continue to govern costs relating to transmission facilities that were in commercial operation pre-merger. *Id.* at p. 7.

The Transmission Reassignment Tariff ("TRT") (Exh. AC-417) governs the rates, terms, and conditions under which American Electric Power Service Corporation ("AEPSC") may resell, assign, or transfer all or a portion of its reserved right to use the transmission system of the post-merger operating companies, or rights that it has reserved or otherwise acquired on the transmission systems of other providers. *Id.* at p. 2.

4. Parties' Concerns:

a. Blue Ridge/ETC/TDU

Only two witnesses raised issues concerning the SIA, STIA, and/or TRT in their direct testimonies. J. Bertram Solomon (Exhs. BRP-200, ETC-400, TDU-400), on behalf of Blue Ridge, ETC, and TDU, [12] was one of them. He argued that the SIA and STIA grant AEP unbridled discretion over the assignment of certain future costs because those agreements provide for "the Agent" (i.e., AEPSC) to determine certain of the elements that affect those costs. Exh. BRP-200 at p. 74. Claiming that Applicants are, in effect, seeking "to be granted pre-approval of any allocation methodology chosen by the Agent" (*id.* at p. 76), Solomon advocated removing the phrase "as determined by the Agent" from the SIA and STIA and adding the phrase "subject to regulatory approval."

As Applicants' Witness explained, however, Applicants are not requesting pre-approval of the allocation methodologies that AEPSC may use in the future. Exh. AC-1110 at p. 100. Rather, any such allocations will be subject to review and challenge under the Act when made. Thus, the rationale for Solomon's proposed modifications to the SIA and STIA fails.

b. Trial Staff:

[12] ETC withdrew its opposition to the merger August 17, 1999; Blue Ridge, November 18, 1999.

System Integration Agreement: Staff Witness Patterson raised several issues relating to the SIA. Applicants agreed to make certain additions and modifications to the SIA to address her concerns, but argued strenuously against modifications that would be at odds with the fundamental objectives of the SIA. Ultimately, Applicants and Staff resolved all but one of their differences concerning the SIA and memorialized their agreement in the July 13, 1999 Stipulation (Ex. AC-1307).

The July 13, 1999 Stipulation specifically provides for:

1. An addition to SIA Service Schedule A, T A2, concerning the allocation of capacity costs, requiring AEP to notify wholesale customers and state regulators when AEPSC determines an allocation among operating companies of new capacity that AEP has constructed or purchased, at which time those entities can exercise their rights to challenge the allocation determination. Exh. AC-1307 at p. 2. This satisfied the concern that Ms. Patterson expressed about the SIA's lack of a list of allocation criteria and the up-front allocation of generation costs for the life of the new facilities. Exh. S-100 at p. 8.

2. A clarifying modification to Article 7:3 of the SIA, concerning capacity exchanges between the two zones, and the addition of definitions of the terms "foregone opportunity cost" and "decremental capacity cost." Exh. AC-1307 at pp. 1 and 2. These amendments satisfied Patterson's concern that the circumstances under which capacity exchanges will be made between the two zones post-merger were unclear. Exh. S-100 at p. 9.

3. An addition to SIA service Schedule D, ¶ D3, concerning the allocation between the zones of revenues realized from off-system sales, to require the Applicants to make an FPA section 205 filing to justify their allocation methodology for the period after the fifth full calendar year following the consummation of the merger, and the addition of a definition for "owned generating capacity." Exh. AC- 1307 at pp. 2 and 3. These additions satisfied Patterson's concerns that the SIA's method of allocating revenues from off-system sales, which allows each zone to receive the equivalent off-system sales credits that it would have absent the merger (and thus keep its ratepayers whole), could be misinterpreted, and could become stale and inappropriate.

Applicants will implement the modifications set forth in the July 13, 1999 Stipulation via a compliance filing after merger approval. Exh. AC-415 at p. 39. Applicants and Staff agree that the SIA, as modified by the Stipulation, is just and reasonable.

System Transmission Integration Agreement: With respect to the STIA, Staff Witness Patterson raised only one issue: In her view, the STIA did not consistently treat the allocation of transmission costs between the two zones for (1) charges paid to third parties for transmission capacity to link the two zones, and (2) costs to build transmission to link the two zones. Exh. S- I 00 at p. 24. She proposed amending the STIA to provide that the costs associated with acquiring or installing new transmission facilities to link the two zones be allocated equally between the two zones. *Id.*

In their rebuttal testimony, Applicants agreed to make such a change to the STIA. Exh. AC-110 at p. 104. Their proposed amendment, to which Staff agreed, is set forth in the July 13 Stipulation. Exh. AC-1307 at p. 4. With this agreed-upon change, the STIA is just and reasonable.

Transmission Reassignment Tariff: Witness Patterson, the only witness who challenged any provision of the TRT, raised several issues regarding this tariff, which governs the resale, assignment, or transfer of transmission capacity that the merged company has reserved on the systems of its operating companies or third parties. 89 Applicants and Trial Staff later resolved all differences regarding the TRT. In the July 13, 1999 Stipulation, Applicants agreed to modify the TRT as follows:

1. Add "in accordance with Commission regulations" to Section 3.3 of the Form of Service Agreement, the provision governing termination of service (Exh. AC-1307 at p. 3). *See* Exh. S-100 at p. 33.

2. Add a clarifying sentence to Article III.D (*see* Exh. AC-1307 at p. 3) addressing refunds for interrupted service. *See* Exh. S-100 at p. 30.

3. Add a sentence to Section IV.C (*see* Exh. AC-1307 at pp. 3 and 4), stating that termination of the TRT terminates underlying service agreements. See Exh S-100 at p. 33.

The TRT, as modified by the July 13, 1999 Stipulation, is just and reasonable.

5. **Applicants-Staff Stipulation:**

The Stipulation between Applicants and Trial Staff (Exh. AC-603) makes it unnecessary to resolve all of the intervenors' issues relating to Applicants' filed rates in Docket No. ER 98-2786-000, the joint open access transmission tariff under which the merged company will provide transmission and ancillary services. Applicants' filed cost of service was $494,055,109 for AEP East and $211.828,157 for AEP West. Exhs. AC-1102 and AC-1103. The Stipulation contains rates that are based on costs of service of $349,712,000 for AEP East and $162,036,000 for AEP West. These figures are substantially below Applicants' filed cost of service and only about 20 percent above the cost of service proposed by AEGIS, the only intervenor that performed a comprehensive cost of service analysis. Exh. AEG-1 (Reising). While the Commission should use Applicant's filed rates as a starting point, this proceeding will have an effect on the rates only if the adjustments to the cost of service would produce rates lower than the stipulated rates.

6. Two Cost of Service Issues Already Have Been Resolved:

In American Elec. Power Service Co., 88 FERC ¶ 61,141 at pp. 61,441-42 (1999) (*Opinion 440*), the Commission held that AEP's use of a gross plant, levelized rate for transmission service was not just and reasonable. The Commission also rejected Applicants' inclusion of generator step-up transformers in the transmission cost of service. Applicants will adopt the Commission's final order (i.e., the Commission's rehearing order) in that docket on both issues, both with respect to this proceeding and with respect to the rates that they will file before consummating the merger. Exh. AC-1110 at pp. 9 and13. There is no need to address those issues in this decision.

7. Intervenors' Other Proposed Adjustments to the Transmission Cost of Service Are Not Just and Reasonable:

a. Applicants' Test Year Is Just and Reasonable:

Applicants' development of their proposed rates based on a 1996 test year was just and reasonable. They will refile their rates prior to consummation of the merger. Exh. AC-1110 at p. 3. Thus the purpose of the rates litigation is to establish cost of service and rate design principles, and not specific rate levels. Hearing Order at p. 61,825. The intervenors' proposed 1998 test year (Exh.AEG- 1 at pp.15 and 16) would have no more probative value with respect to the principles applicable to the post-merger rates than would a 1996 test year.

Intervenors have not offered a just and reasonable alternative to Applicants' 1996 test year. AEGIS' so-called 1998 test year is based on a hodgepodge of estimates derived from 1996 and 1997, together with unaudited 1998 data. Exh. AEG-1 at pp.14 and 19. That test year violates basic cost of service principles. *See Pacific Gas and Elec. Co.*, 53 FERC ¶ 61,146 at p. 61,520 (1990).

b. Applicants' Calculation of Transmission Revenue Credits Based on 1996 Data Is Just and Reasonable:

Applicants developed their transmission cost of service by crediting 1996 revenues from short-term and non-firm transmission service against their 1996 costs. In contrast, the intervenors have proposed to adjust the 1996 cost of service by crediting revenues received from short-term and non-firm transmission service in 1998. Exh. AEG-1 at p.19. The intervenors' proposal to mix 1996 costs and 1998 revenues is inconsistent with basic ratemaking principles. The Commission does not permit post-test year adjustments

to the cost of service unless the test year estimates were unreasonable when made or subsequent events demonstrate that the estimates would produce unreasonable results. *Pacific Gas*, 53 FERC at p. 61,520. Applicants have used a historic test year, and there is no question of the reasonableness of estimates. Also, post-test year events do not indicate that the use of the historic data would produce unreasonable results in the future because Applicants will refile their rates prior to consummation of the merger.

c. Other Intervenor Positions:

Intervenors unsuccessfully urged a number of other proposals that do not require extensive treatment. Their value was simply not convincingly demonstrated on this record. The most important among them were:

1. AEGIS' proposed functionalization of GSU-related equipment.
2. Exclusion of radial facilities from the transmission cost of service.
3. Challenges to Applicants' West Zone rates.
4. Selective exclusion of items of cost of service.

5. Rate of Return on Common Equity:

Applicants' Witness Barber recommended a 1 1.75 percent rate of return on common equity for AEP and CSW as a combined entity. He applied the standards for determining the rate of return established in *Bluefield Water Works & Improvement Co. v. PSC of West Virginia*, 262 U.S. 679 (1923) and *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

In *Bluefield*, the Court said:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public *equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties;* but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. 262 U.S. 679 at 692-693 (emphasis added

In *Hope*, the Court stated that:

> Rates enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed ... It is not the theory but the impact of the rate order which counts. 320 U.S. 591 at 605.

Applying the *Bluefield and Hope* standards requires the analysis of all available data. Thus rather than rely on a single methodology, Barber considered several methods of determining the cost of common equity.

Witness Barber considered variations of the DCF methodology. The first, or "conventional" DCF methodology resulted in a minimum cost of common equity of approximately 5.65 percent for AEP (Exh. AC-1209) and 6.44 percent for C SW (Exh. AC-1215). He testified that very little reliance should be placed on the results obtained using this method because the unrealistic assumptions produce such a low return as to conclusively demonstrate its invalidity. Exh. AC-1200 at p. 13. Two modifications to conventional DCF methodology produce more realistic results. The first alternative replaces the market value of stock with its book value because the market value ignores the fact that the current market price is in part based upon actual recent and anticipated future market appreciation. Exh. AC-1200 at p. 15. This alternative calculation results in a minimum cost of common equity of 10.13 percent for AEP and 10.30 percent for CSW. Exhs. AC-1209 and AC-1215. The second alternative recognizes that stock prices are based on factors other than dividend expectations. Barber identified three elements to be considered: current yields, expected gains in dividends and expected change in market value. AC-1200 at p.16. He looked at actual annual increases in the market value of AEP and CSW common stock over the last ten years, excluded the highest and lowest years and then assumed that investors are anticipating ating that future market appreciation will be less than was realized over the past ten years. The result is a minimum required return on equity of 10. 3 9 percent for AEP and 1 1.44 percent for CSW. Exhs. AC-1209 at p. 2 and AC-1215 at p. 2.

Barber also considered and explained the effect on the DCF method of stock prices' divergence from book values, other methods of determining the proper return for Applicants, comparable earnings methodology, and the risk premium methodology. The results are summarized in Exh. AC-1208 at p. 12.

The effect of Barber's evidence, which was persuasive and not weakened by any cross-examination or contradictory evidence, is a finding that reasonable rates of return on common equity are 12.0 percent for AEP, 11.5 percent for CSW, and 11.75 percent for the merged company.

6. Rate Design:

AEGIS Witness Reising proposes that AEP's rates for point-to-point transmission service be designed using a 1-CP allocator. That proposition is untenable. There is no

factual or legal basis on which to base it. The Commission decides whether a transmission rate should be designed on a 1-CP basis or a 12-CP basis on the facts of each case. Order 888 at 31,738. A transmission system must be designed to meet the changes in demands placed on it, which are a function of peak loads, changes in customer load patterns, scheduled maintenance and unscheduled outages on the transmission system and generator outages. Exhs. AC-1110 at p. 86 and AC-1108. Consequently, AEP plans its transmission system to meet each monthly peak and to deal with all reasonable contingencies.

AEP's peak loads meet the tests established by the Commission for determining whether a utility is a 12-CP company. *See Illinois Power Co.*, 11 FERC ¶ 63,040 at pp. 65,248-49 (1980), *modified*, 15 FERC ¶ 61,050 (1981); *Carolina Power & Light Co.*, 4 FERC ¶ 61,107 at p. 61,230 (1978). *See also* Exh. AC-1108. The Commission has continued to apply these tests in designing transmission rates after the issuance of Order 888, demonstrating that the tests are appropriate for the design of transmission rates. *Niagara Mohawk Power Corp.*, 82 FERC ¶ 63,018 at p. 65,143 (1998); *Consumers Energy Co.*, 86 FERC ¶ 63,004 at p. 65,032 (1999). It follows that a 12-CP rate design is appropriate for AEP.

It is a basic principle of ratemaking that rate design should have no impact on the recovery of revenues. Rate design is revenue-neutral if the determinants that are used to calculate customer bills are consistent with the determinants that are used to design the unit charges. *Northeast Utils. Serv. Co.*, 62 FERC ¶ 61,294 at pp. 62,906-07 (1993). AEGIS violated this basic principle of rate design by proposing to design the Applicants' rates based on the annual peak, but to bill customers based on their monthly peak loads. The result of that would be unreasonable because it would guarantee that the transmission provider could not recover its cost of service. *See* Exh. AC-1110 at p. 86.

Applicants' rate design, as proposed, must be approved.

IV. ULTIMATE FINDINGS AND CONCLUSIONS

Pursuant to the Commission's orders, and upon consideration of the entire record of these proceedings, I find and conclude:

1. Applicants' request to merge their jurisdictional facilities, with the mitigation measures to which they have committed, is consistent with the public interest;

2. The rates, terms, and conditions of the three rate schedules filed in Docket No. ER98-2770-000, as modified by the stipulation entered into by Applicants and Staff, are just, reasonable, and not otherwise unlawful; and

3. The Joint Open Access Transmission Tariff providing for post-merger transmission and ancillary services filed in Docket Nol ER98-2786-000, as modified by the stipulation entered into by Applicants and Staff, is just, reasonable, and not otherwise unlawful.

V. ORDERS

It is, therefore, ordered:

1. DP&L's motion for official notice, described above, is denied;

2. The merger herein proposed is approved to the extent set out in the body of this initial decision;

3. If refunds are due any customer as a consequence of any action, revision, or amendment required to conform to the rulings, findings, or conclusions made in this initial decision, then 90 days after the Commission approves such action, revision, or amendment, Applicants must refund all amounts collected in excess of those that would have been payable under any such action, revision, or amendment, with interest from the date of payment to the date of refund as provided in this Commission's rules and regulations. *See* 18 CFR 35.19(a)(2) (1999); and

4. Within 60 days after making any refund payment required by this initial decision, Applicants must file with this Commission a report in writing describing the payee of such payment, the amount of refund paid, the amount of interest paid, and the methods by which such refund and interest were determined and calculated.

Joseph R. Nacy

Joseph R. Nacy
Administrative Law Judge